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**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Order Instituting Rulemaking to Enhance the Role of Demand Response in Meeting the State's Resource Planning Needs and Operational Requirements.	Rulemaking 13-09-011

REPLY COMMENTS OF THE CALIFORNIA LARGE ENERGY CONSUMERS ASSOCIATION TO RESPONSES TO ALJ HYMES' RULING OF MAY 20, 2016

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Pursuant to Administrative Law Judge (ALJ) Hymes' Ruling dated May 20, 2016 (Ruling), the California Large Energy Consumers Association (CLECA) submits reply comments to the comments filed on July 1, 2016 in response to questions posed by the ALJ in that Ruling.

I. INTRODUCTION

The purpose of the comments was "to further develop a record to support a decision providing Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (jointly, the Utilities) guidance for developing applications for 2018 and beyond demand response activities and budgets."[1] CLECA notes that there were numerous comments filed on July 1, as well as comments from Olivine filed on July 6, and that these comments displayed considerable diversity. Because of this diversity, CLECA provides its reply comments to

[1] Ruling at 1.

each party, rather than by the category of questions posed by the ALJ in the May 20 Ruling.

II. CLECA RESPONSE TO PARTY COMMENTS

A. Southern California Edison Company (SCE)

SCE states: “A program only used to alleviate emergency situations would be integrated as a RDRR[2] and would only be dispatched when market prices reached the resource’s bid price of at least $950/MW and an emergency was declared by the CAISO[3].” This is not correct. RDRR is dispatched based on a contingency as set forth in CAISO Operating Procedures 4420 and, once dispatched, sets the real-time market clearing price at $950/MWh. It can be dispatched before market prices reach $950/MWh.

B. San Diego Gas & Electric Company (SDG&E)

SDG&E states that DR in the future should be procured through all-source Requests for Offers (RFOs).[4] While CLECA supports all-source RFOs, during this period of significant transformation in the DR market there are advantages to solicitations to procure DR resources alone and to evaluate them against each other. We note that the Commission has conducted stand-alone solicitations for storage resources. In addition, the Loading Order status of DR may not be fully captured in an all-source RFO.

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2 Reliability Demand Response Resource

3 California Independent System Operator

4 SDG&E July I comments at 4-5.

C. Pacific Gas and Electric Company (PG&E)

PG&E suggests that it may be appropriate for utilities to "offer customers and aggregators the ability to elect their availability to provide value to the grid in a manner that reflects customers' varied opportunity costs."[5] CLECA find this a worthwhile direction to pursue, since the ability of customers to participate in DR does vary depending on the nature of the customer and the impact of load changes on its operations.

CLECA also supports PG&E's comments on a penalty structure for DR, particularly where it states:

> The Commission should consider that each DR program has its own balance of risks and rewards which is unique to each program. The Commission addressed this to a limited extent in D.16-06-029 when it found that the CBP[6] was justified in having a different penalty structure from the DRAM[7] because the CBP has more risks. Having a portfolio of DR programs with different risk/reward balances is necessary so that customers can decide which risk/reward profile best suits their capabilities. The penalty structure of a DR program should reflect several factors such as payment level, degree of predictability required of the program (enforced through a penalty mechanism), availability of the program, and speed of dispatch. As an example, the Base Interruptible Program (BIP) pays a comparatively high capacity payment but it is highly predictable in its performance (the Firm Service Level is determined annually), is available 24 hours day, seven days a week, year-round, and responds within 30 minutes of being notified by the IOU. It therefore has, and should continue to have, a penalty structure that is much more rigorous than the CBP, which receives a lower payment than BIP, allows for monthly adjustments to nominated MWs, and has other more flexible terms. PG&E believes these differences are appropriate. (footnote omitted)[8]

Reliability DR Resources, like BIP, are required to be available to meet system or local contingencies on short notice and must be relied upon to support the system or local grid, often under challenging circumstances. The penalties for non-performance

[5] PG&E July 1 comments, at 3, 15, and 26.
[6] Capacity Bidding program
[7] Demand Response Auction Mechanism
[8] Id. at 41-42.

are thus severe[9] and far exceed CAISO grid "penalties" like the risk of Uninstructed Imbalance Energy charges (or payments) or being subject to the Resource Adequacy Availability Incentive Mechanism.

CLECA also generally agrees with PG&E's response to the question on the alignment of capacity incentives.

> For similar reasons explained in PG&E's response to Question 9 on the standardization of non-performance penalties, it would be inappropriate to align capacity incentives among all IOU and third-party DR programs. Each DR program requires different degrees of predictability, response capabilities, and flexibility in use. Furthermore, if the Commission aligns capacity payments among all DR programs, it would defeat the purpose of having different DR programs because DR customers would simply enroll in the program with the least rigorous operational requirements and penalty structure. Finally, aligning capacity payments with the results of competitive procurement is not certain to result in incentive payments that are considered cost effective according to the DR Cost Effectiveness Protocols because competitive procurement is not guaranteed to result in a cost-effective price.
>
> PG&E sees no advantages to moving to a competitive framework for all capacity incentives. Disadvantages of moving to a competitive framework for all capacity incentives are that 1) it would prevent the IOUs from designing programs that provide a unique balance of payment level, degree of predictability required of the program, availability of the program, speed of dispatch and frequency of enrollments; 2) it could open the door to potential gaming by DR providers if the DR market is not sufficiently liquid, and 3) it may reduce the certainty of a specific level of capacity payments to DR providers.[10]

All DR, whether utility programs or procured third-party DR, does not need to provide the same level of service and thus should not have the same incentives, just as it should not have the same penalties.

D. Office of Ratepayer Advocates (ORA)

ORA supports a future regime where utilities administer DR programs but the DR

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9 $6/kWh to up to $15/kWh for excess energy above the Firm Service Level.

10 Id. at 42-43.

is provided by third parties alone.[11] Furthermore, ORA recommends that the DR Auction Mechanism (DRAM) be used in the future for all procurement.[12] While procurement of DR through an auction holds promise, CLECA reiterates its opening comments that there are no results yet regarding the success of the DRAM winners bidding into and being dispatched by the CAISO, and thus contends that these recommendations are at best premature. Furthermore, CLECA believes that utility DR programs have value and should be continued for customers who prefer them or who are not recruited by third parties. Thus, CLECA opposes ORA's proposals to have DR only provided by third parties and to have all DR provided through the DRAM.

E. California Energy Storage Alliance (CESA)

CESA cites a goal of achieving DR equal to five percent of load from the 2014 DR Settlement Agreement but fails to note that the Commission never adopted that Settlement Agreement.[13]

CESA, as well as other parties[14], states that storage should be able to provide both load modifying and supply-side DR. In this case, CESA and the others are conceiving of load modifying DR as "supporting local reliability for the LSE."[15] However, the Commission has focused on load modifying DR as being rate-related and resulting in the reshaping of the load forecast. This is not accomplished by distributed energy resources, such as storage, relieving overloads on distribution system. Thus, it appears that there is some confusion over the definition of load modifying DR, despite the

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[11] ORA July 1 comments at 2-3.
[12] Ibid. pp. 12-13. OhmConnect at 6.
[13] CESA July 1 comments at 3-4.
[14] See discussion of comments of Advanced Microgrid Systems below.
[15] Id at 6. Also, Advanced Microgrid Systems at 6.

Commission's definition of the term in D. 14-03-026.[16] There may also be a need for a new term to define the use of DR to address reliability concerns on the distribution system. Additionally, local reliability on the distribution system is not a matter for the load-serving entity (LSE) but rather a matter for the distribution system owner.

CESA raises a concern that "one key barrier to unlocking this innovation [multiple value streams] has been the strict dual participation rules that, for example, restrict energy storage to participation in just one DR program."[17] CESA may not understand that the dual participation rules are designed to limit DR participation to one capacity and one energy program in order to avoid double payment for the same service. Furthermore, California Independent System Operator (CAISO) rules limit a resource to one DR provider (DRP) and one Load Serving Entity (LSE).

The concept of providing "multiple value streams" is being considered in the Storage OIR (R. 15-03-011). One key issue in that proceeding is that while it may be desirable for a resource to provide additional services and be eligible for additional sources of compensation, it is very important that a resource not be paid twice for the same service or be paid for a service it was already providing for another reason. This issue could possibly be considered in the 2018 utility DR application cases as well, but there are clearly overlap issues.

CESA also argues that storage does not need baselines because load reductions can be measured directly.[18] Advanced Microgrid Systems (AMS) makes a similar

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16 "It is reasonable to adopt the following definitions for bifurcating the demand response programs: Load Modifying Resource demand response reshapes or reduces the net load curve and Supply Resource demand response is integrated into the CAISO market." D. 14-03-026, Conclusion of Law 5.

17 Id. at 12.

18 CESA at 13.

comment.[19] However, there is no requirement for separate metering of the output of the storage device. Under the Energy Storage and Distribution Energy Resources (ESDER) Phase stakeholder process at the CAISO, separate metering is an option, and facilitates a baseline calculation, but is not required.[20] Furthermore, the Commission in D. 14-05-033 created two constraints to such submetering that fall within its jurisdiction over retail metering. These are clearly relevant to a case where behind-the-meter (BTM) storage or other resources are part of a DR resource being bid into the CAISO markets as a Proxy Demand Resource (PDR) or RDRR.

First, the Commission decided that Net Energy Metering (NEM) generators that operate with energy storage do not require a Net Generation Output Meter (NGOM) if the energy storage device is less than 10 kW in size.[21] Second, the Commission limited metering fees to the customer to no more than $600.[22] In addition, it is not clear if there is a requirement that the submeter be revenue quality, although CAISO settlement requires settlement quality meter data that the Commission, as the Local Regulatory Authority, has determined is revenue quality meter data.[23]

In the first case, there is no metering requirement. In the second, there is an outstanding issue of who pays for the submetering if it is required to participate in the wholesale market. CLECA has previously expressed a concern that if the fee is limited

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19 AMS at 13.

20 ReisedDraftFinalProposal-EneryStorageDistributedEnergyResources.pdf at 21-23.

21 D. 14-05-033, Conclusion of Law 8.

22 D. 14-05-033, Ordering Paragraph 10.

23 Revenue quality meter data are data that have been validated, edited and estimated (VEE'd) in accordance with the Direct Access Standards for Metering and Meter Data as described in Electric Rule 22. CAISO settlement quality meter data comes from a revenue quality meter that has been certified by the CAISO or the Local Regulatory Authority (e.g. this Commission) and has been VEE'd. It is used for CAISO market settlements.

to $600, other customers might end up paying for any costs in excess of that amount, representing a cost-shift to non-participating customers. Thus, while the CAISO Energy Storage and Distributed Energy Resources (ESDER) stakeholder process in Phase 1 showed that there are baseline issues for storage, the assumption of separate metering is not an assurance that it will exist.

F. OhmConnect

OhmConnect argues that "because the utilities are presently the largest buyers and sellers of DR products, the Commission should require that an independent entity (e.g. the CAISO) administer the procurement mechanisms for DR products, rather than the utilities themselves.[24] EDF makes a similar argument.[25] CLECA notes that it is not part of the CAISO's mission to run procurement auctions and that, indeed, there was widespread stakeholder objection to a prior CAISO proposal to run an auction as part of the revision of the Capacity Procurement Mechanism (CPM).

OhmConnect also says that all caps on Rule 24/32 registrations would be eliminated.[26] However, OhmConnect does not provide a justification of why ratepayers should pay for the systems required to support large numbers of registrations that a lack of a cap might suggest, regardless of whether these registrations actually transpire. This is a matter that the Commission addressed in D. 15-03-042, where it found that "[t]he record in this proceeding does not include any evidence indicating a level of customer participation in direct participation that requires the Applicants to implement

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24 OhmConnect at 6. EDF at 6.
25 EDF at 6.
26 OhmConnect at 9.

processes for large scale direct participation."[27] In a very recent decision on an intermediate stage for Rule 24/32 registrations, the Commission stated that "we require that any request for increasing funding associated with increased customer registrations should address the issues of whether the increase should be considered large scale, mass market implementation. If the Commission determines that large scale, mass market implementation is necessary a separate application by the Applicant shall be required, as previously directed by the Commission in D. 15-03-042."[28] Thus, this is not the proceeding in which to address this issue.

G. Nest

Nest states that DR should provide load reductions "through the cooling season"[29] but ignores the fact that DR can provide load adjustments at any time of year unless it comes from air conditioning. Indeed, as was experienced on February 6, 2014 when there was a shortage of natural gas for power generation, DR played a key role in supporting the grid at a time when there was no air conditioning load, particularly the BIP program. Furthermore, the ramping needs for renewable integration that DR may assist in meeting are greatest in the winter and spring months, not the summer months.[30]

Nest's primary focus appears to be to achieve higher levels of incentives for programmable communicating thermostats.[31] While these may indeed be useful in achieving DR from some customer segments, the Commission in D. 16-06-029 in this

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[27] D. 14-03-042, Finding of Fact 8.
[28] D. 16-06-008 at 27.
[29] Nest July comments at 2.
[30] CAISO FinalFlexibleCapacityNeedsAssessmentFor2017.pdf at 13.
[31] Nest July 1 comments at 7, 8, and 15.

proceeding correctly took a measured approach towards incentives for this technology; the Commission appropriately weighed the impact on ratepayers in paying for these incentives. It found that Nest provided "no evidence to support its conclusion that a $100 rebate would provide higher participation rates than a $75 rebate or that such an increase would result in 50,000 or more customers participating. Furthermore, the record of this proceeding does not include a cost-effectiveness analysis of the program with a $100 rebate."[32]

H. California Independent System Operator (CAISO)

The CAISO states that DR should be able to provide regulation and real-time balancing services[33], but there are no provisions in the CAISO tariff to permit these uses of DR. CLECA encourages expeditious development of these options.

I. Environmental Defense Fund (EDF)

EDF states that the DRAM auction should not be hosted by utilities but by the CAISO or "another objective market oversight entity."[34] As noted before in these comments, the CAISO does not currently do competitive procurement of resources; furthermore, it is not clear what other "objective market oversight entity" would exist.

EDF also states that it "believes the Commission should avoid a long-term situation where the IOUs are scheduling their DR as a first priority over DR from third-

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32 D. 16-06-029 at 27.
33 CAISO July 1 comments at 2.
34 EDF at 6.

party providers when the third party resource is available at a lower cost and with adequate "fit" (i.e. has performance characteristics akin to utility DR programs)." [35] EDF has provided no support for its assertion that utilities are scheduling their DR in preference to that of third party providers. Indeed, DRAM participants do not use the utility as a scheduling coordinator. It is thus difficult to understand to what EDF refers or whether it is an issue.

EDF states that utilities should procure through DRAM until the DRAM cap is met.[36] However, EDF says nothing about cost-effectiveness, which would be an issue if the only goal were to fill up the program to the cap. EDF also says that it "believes that DRAM resources are cost-effective".[37] However, it provides no evidence to support this claim.

J. Join Demand Response Parties (JDRP)

JDRP propose that 2018 be another bridge funding year.[38] Future guidance on DRAM and any setting of DR goals for 2018 and beyond should be informed by the results of a vetted DR Potential Study and actual DRAM results. Whether there is a need for additional bridge funding in 2018 should depend on when the final results of the DR Potential Study are received and vetted, and analysis of results from the 2016 and 2017 DRAM auctions.

JDRP claim that "if customers are paid more and dispatched less frequently, then everyone wants to join that party."[39] This appears to be a criticism of reliability DR

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[35] Id. at 4.
[36] Id. at 4-5.
[37] Id. at 10.
[38] JDRP July 1 comments at 2.
[39] JDRP at 18-19.

resources (RDRR), which are only dispatched for contingencies and thus not as frequently as proxy DR resources (PDR), which are also dispatched on price. However, CLECA points out that, as noted above, the penalties for non-performance for utility DR programs that are being or will be bid into the CAISO markets as RDRR are severe and rigid, as befits the reliability-based nature of the programs. Thus, the frequency of dispatch is not the only consideration. It is not clear if all DR participants would be willing to pay $6-15/kWh for every kWh they use in excess of their firm service level commitment.

JDRP also say that new DR technologies need regulatory support, like that received by storage.[40]

> While some forms of DR have been around for a while, there are newer forms of DR that are emerging that are experimental. These forms of DR, fast response, frequent dispatch, and load following, require the same regulatory support as new technologies, like storage receives, to gain market acceptance. The Commission should distinguish among types of DR in terms of how value is provided to support entry into a nascent market."[41]

CLECA notes that there are many new resources that would like to get regulatory support but that all of this support must come from ratepayers. There should be a limit to the number of new technologies that ratepayers are supporting, particularly when they are new and not tested for cost-effectiveness.

JDRP proposes that a mechanism that could be included in future DR programs "would be a graduation in the capacity value of a program as resources receive more frequent calls."[42] CLECA believes that the Commission should consider increasing the value of DR if it is called considerably more frequently that at present. However, more

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40 Id. at 19.
41 Id. at 19.
42 Id. at 32.

frequent calls are more of an energy issue rather than a capacity issue.[43] Perhaps there can be a consideration of more frequent use to provide flexibility, which may ultimately have a higher capacity value when the flexible capacity requirement is revised in the resource adequacy proceeding.

K. The Utility Reform Network (TURN)

TURN states that it concludes from the DR Potential Study that reliable DR "in the future depends on reducing the reliance on the large C&I BIP program, due to the significant reduction in response with frequency of dispatch, and instead shifting toward a more even mix of DR from residential, small and medium commercial ("SMB") and large commercial and industrial ("C&I) customers..".[44] TURN cites Appendix F of the Interim DR Potential Study in support. We note that the figure referred to by TURN entitled "Large C&I Effect of More Frequent Dispatch on Achievable Participation" does not have a parallel graph for residential or small and medium commercial customers and thus no relative conclusion can be reached about the impact of more frequent dispatch on large C&I customers compared to others. Furthermore, TURN singles out the BIP program. BIP is a reliability DR program which absolutely must be there when called and has substantial penalties for non-performance. Its reliability is its primary feature. Unless overall system reliability is much reduced, it will be called as needed but not often. If TURN is suggesting that it should be replaced by other DR resources will similar penalty provisions, that might be a reasonable comparison. However, TURN does not make that point.

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[43] Id. at 32.

[44] TURN July 1 comments at 4.

TURN also states that "the goal must be to phase out all load modifying DR starting in 2018, except those DR products that can be locally dispatched."[45] As with other parties, TURN seems to apply the definition of load modifying DR to DR that can reduce demand on the distribution system during times of overload problems rather than to load modifying DR provided by TOU or dynamic rates that re-shapes the load curve. The latter is the Commission's own definition, as noted before in these comments. Furthermore, TURN does not provide a basis for eliminating the types of load modifying DR that the Commission has adopted, such as those based on rates, that re-shape the load curve.

As for TURN's comment that air conditioner cycling programs have similar incentives to BIP but are used more often[46], CLECA notes that air conditioner cycling programs have both price and reliability triggers whereas BIP does not. Furthermore, residential and industrial opportunity costs are not necessarily the same.

L. Advanced Microgrid Systems (AMS)

AMS argues that DR, with a focus on storage-supported DR, can provide "multiple, simultaneous services."[47] It further states that "DR resources that can perform multiple functions, such as those that perform both load modifying and supply-side DR functions, should be prioritized."[48] AMS refers to "encouraging resources to participate in multiple programs" and "value stacking".[49] CLECA points out that the issue of providing multiple services is directly related to an issue before the Commission in the

45 Id. at 12.
46 ID at 17.
47 AMS July I comments at 3.
48 Id. at 6. Again there appears to be confusion as to the definition of load modifying DR.
49 Id. at 8.

storage rulemaking (R. 15-03-011), which is how to define and compensate multiple services without provide double-compensation for the same service. For example, one resource cannot provide reserve-type ancillary services and energy at the same time unless it is from different parts of the resource because reserve-type ancillary services provide a call on energy in the future and that energy cannot be committed elsewhere. The Commission will have to decide whether it wants to address the matter of appropriate compensation for multiple services for DR alone in this proceeding and how to coordinate its assessment in parallel with the storage rulemaking. Certainly the results should not be inconsistent.

III. CONCLUSION

CLECA appreciates this opportunity to provide reply comments in response to the ALJ's questions posed on May 20, 2016.

Respectfully submitted,

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